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(54) **CARBON DIOXIDE FRACTIONALIZATION PROCESS**

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(Continued)

(58) **Field of Classification Search**

USPC 585/802; 208/92; 96/108; 95/214; 62/621–624

See application file for complete search history.

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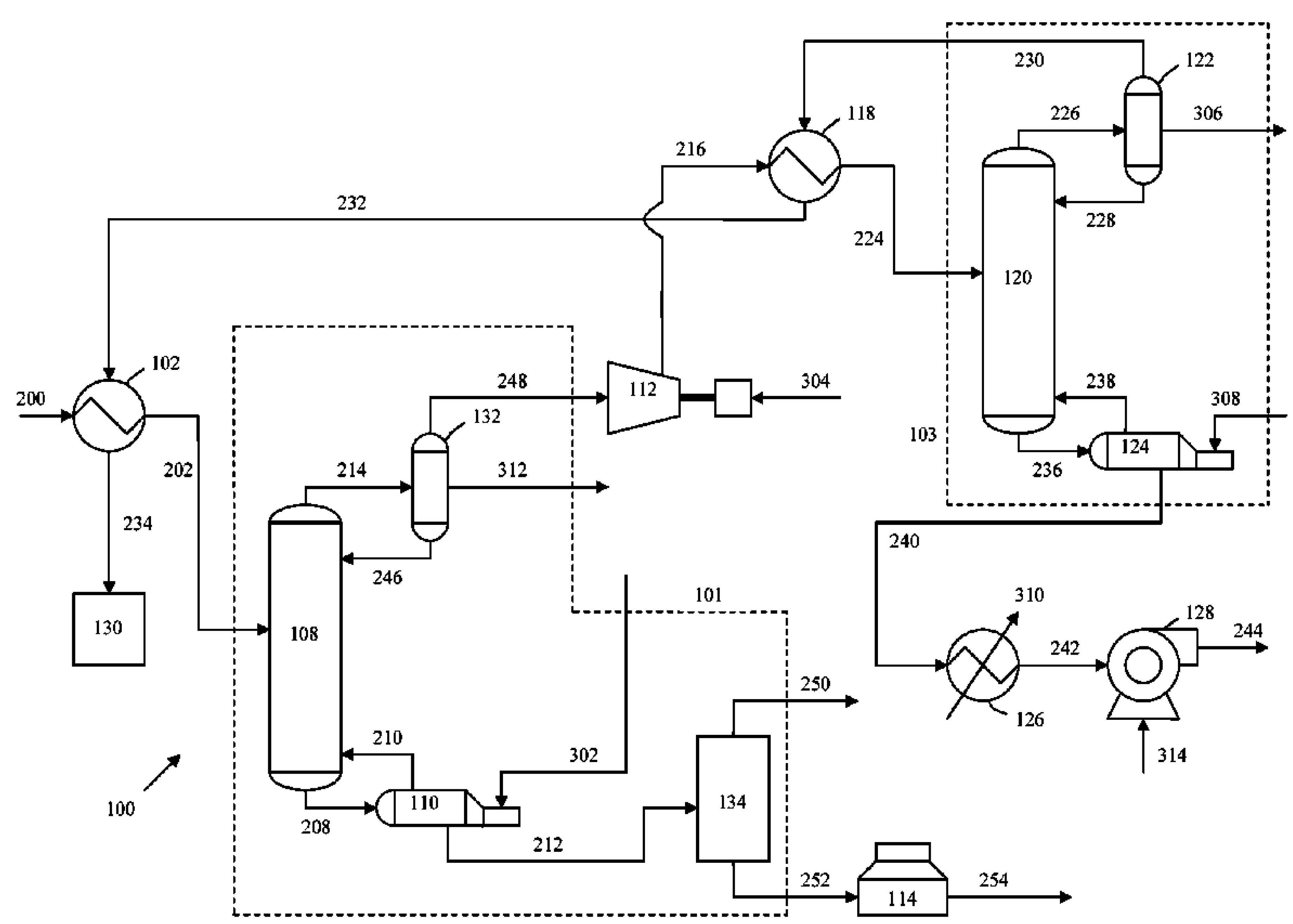
(57) **ABSTRACT**

A method comprises separating a hydrocarbon feed stream having carbon dioxide into a heavy hydrocarbon stream and a light hydrocarbon stream. The light hydrocarbon stream is separated into a carbon dioxide-rich stream and a carbon dioxide-lean stream. At least a portion of the carbon dioxide-lean stream is fed to a hydrocarbon sweetening process. Another method comprises receiving a hydrocarbon feed stream that comprises 30 molar percent to 80 molar percent carbon dioxide. A heavy hydrocarbon stream is separated from the hydrocarbon feed stream, wherein the heavy hydrocarbon stream comprises at least 90 molar percent C_{3+} hydrocarbons. A carbon dioxide-rich stream is separated from the hydrocarbon feed stream, wherein the carbon dioxide-rich stream comprises at least 95 molar percent carbon dioxide.

20 Claims, 2 Drawing Sheets



Related U.S. Application Data

division of application No. 12/824,382, filed on Jun. 28, 2010, now Pat. No. 8,709,215, which is a division of application No. 11/621,913, filed on Jan. 10, 2007, now Pat. No. 7,777,088.

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C10G 31/00	(2006.01)
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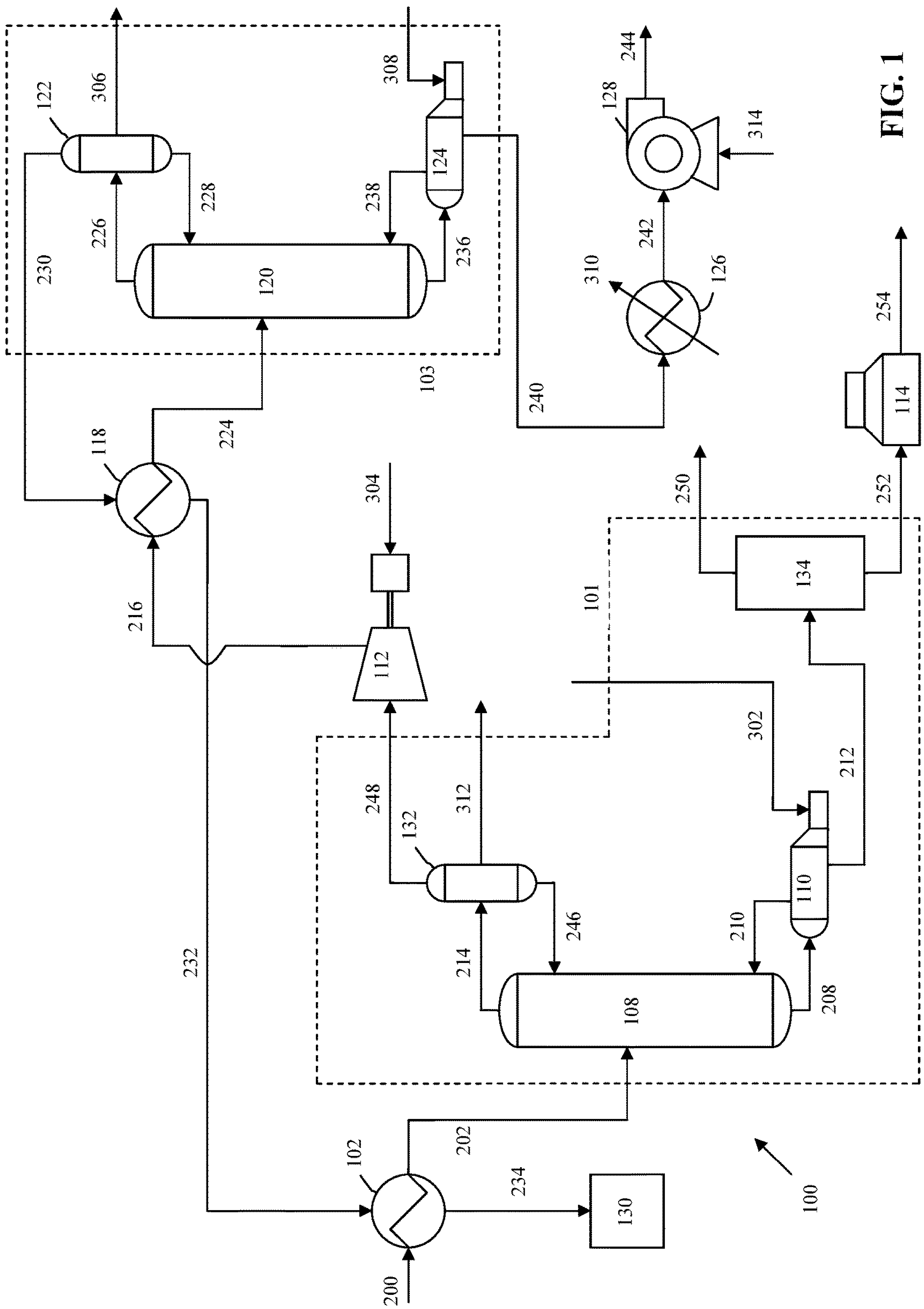
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FIG. 1

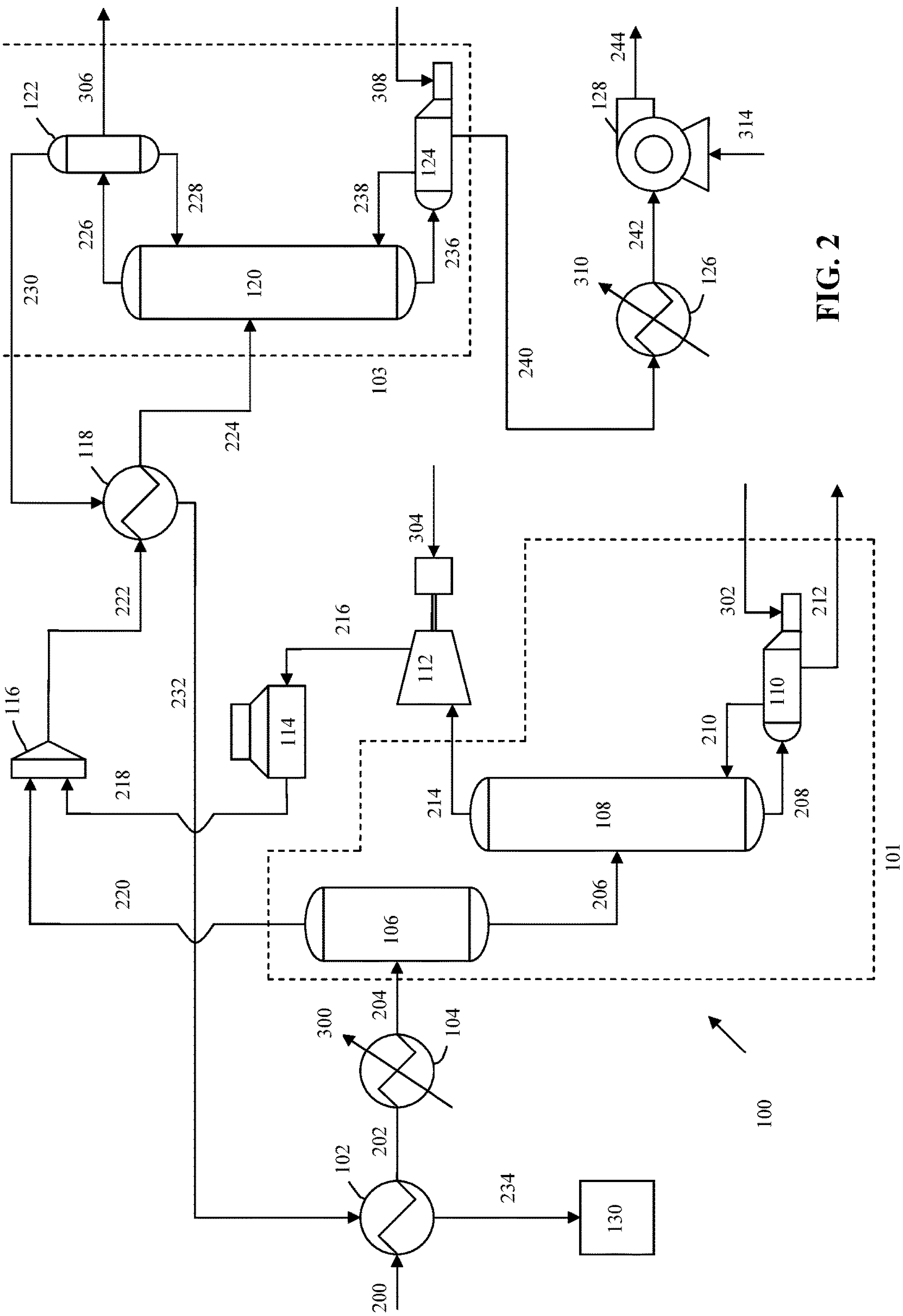
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FIG. 2

CARBON DIOXIDE FRACTIONALIZATION PROCESS

CROSS-REFERENCE TO RELATED APPLICATIONS

This application is a continuation of U.S. patent application Ser. No. 14/200,346, filed Mar. 7, 2014, which is a divisional of U.S. patent application Ser. No. 12/824,382, filed Jun. 28, 2010, now U.S. Pat. No. 8,709,215, which is a divisional of U.S. patent application Ser. No. 11/621,913 filed Jan. 10, 2007, now Reissued U.S. Pat. No. RE 44,462, the contents of all of which are incorporated herein by reference as if reproduced in their entireties.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

Not applicable.

REFERENCE TO A MICROFICHE APPENDIX

Not applicable.

BACKGROUND

Carbon dioxide is a naturally occurring substance in most hydrocarbon formations. While the carbon dioxide concentration will depend on the location of the formation, carbon dioxide concentrations as high as eighty percent are common in many areas, such as West Texas. Moreover, the implementation of tertiary recovery operations, such as carbon dioxide injection into the subterranean wellbore, can increase the carbon dioxide concentration within the produced hydrocarbons. In either case, the carbon dioxide concentration of the produced hydrocarbons may be sufficiently high to require the carbon dioxide concentration to be reduced before the hydrocarbons can be refined or further processed.

Several solutions are known for reducing the carbon dioxide concentration or "sweetening" a hydrocarbon stream. For example, amine processes, physical solvent processes, membrane processes, and carbon dioxide recovery processes have all been used to sweeten hydrocarbon streams. The processing facilities employing these hydrocarbon sweetening processes are generally sized for a specific processing capacity and hydrocarbon feed stream composition. As such, when the carbon dioxide concentration of the hydrocarbon feed stream increases or additional feedstock comes online, then an additional processing facility must be constructed to compensate for the change in hydrocarbon feed stream composition or the increased feedstock. The construction of a new processing facility is undesirable because of the substantial capital cost, operating costs, and time delay inherent in such a solution.

SUMMARY

In one aspect, the disclosure includes a method comprising separating a hydrocarbon feed stream having carbon dioxide into a heavy hydrocarbon stream and a light hydrocarbon stream. The light hydrocarbon stream is separated into a carbon dioxide-rich stream and a carbon dioxide-lean stream. At least a portion of the carbon dioxide-lean stream is fed to a hydrocarbon sweetening process.

In another aspect, the disclosure includes a method comprising receiving a hydrocarbon feed stream that comprises 30 molar percent to 80 molar percent carbon dioxide. A heavy hydrocarbon stream is separated from the hydrocarbon feed stream, wherein the heavy hydrocarbon stream comprises at least 90 molar percent C_{3+} hydrocarbons. A carbon dioxide-rich stream is separated from the hydrocarbon feed stream, wherein the carbon dioxide-rich stream comprises at least 95 molar percent carbon dioxide.

In a third aspect, the disclosure includes a method comprising receiving a hydrocarbon feed stream that comprises carbon dioxide. The hydrocarbon feed stream is separated into a carbon dioxide-lean stream and a carbon dioxide-rich stream. The carbon dioxide-lean stream comprises at least 20 molar percent less carbon dioxide than the hydrocarbon feed stream, and the carbon dioxide-rich stream comprises less than 10 molar percent hydrocarbons.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** is a process flow diagram of one embodiment of the carbon dioxide fractionalization process; and

FIG. **2** is a process flow diagram of another embodiment of the carbon dioxide fractionalization process.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

Disclosed herein is a carbon dioxide fractionalization process that may be positioned in front of an existing hydrocarbon sweetening process to increase the processing capacity of the hydrocarbon sweetening process. Specifically, the carbon dioxide fractionalization process purifies the hydrocarbon feed stream by removing at least some of the carbon dioxide and the heavy hydrocarbons from a hydrocarbon feed stream. The purification of the hydrocarbon stream reduces the carbon dioxide and heavy hydrocarbon loading on the hydrocarbon sweetening process, thereby increasing the processing capacity of the hydrocarbon sweetening process. Furthermore, the carbon dioxide fractionalization process produces a carbon dioxide-rich stream that may be injected into a subterranean formation.

FIG. **1** illustrates one embodiment of the carbon dioxide fractionalization process **100**. The carbon dioxide fractionalization process **100** separates a hydrocarbon feed stream **200** into a heavy hydrocarbon stream **254**, an acid gas stream **250**, a carbon dioxide-rich stream **244**, and a carbon dioxide-lean stream **234**, the compositions of which are discussed in detail below. The carbon dioxide fractionalization process **100** receives the hydrocarbon feed stream **200** and may pass the hydrocarbon feed stream **200** through a heat exchanger **102** that uses the cooled carbon dioxide-lean stream **232** to reduce the temperature of the hydrocarbon feed stream **200**. A first separation unit **101** that comprises one or more of a separator **108**, a reboiler **110**, a condenser **132**, and a separator **134** may then remove the heavy hydrocarbons from the cooled hydrocarbon feed stream **202**. Specifically, the separator **108** separates the cooled hydrocarbon feed stream **202** into a bottom effluent stream **208** and a top effluent stream **214**. The top effluent stream **214** may then be fed into a condenser **132**, which may give off energy **312** by being cooled, and separates the top effluent stream **214** into a reflux stream **246** and a light hydrocarbon stream **248**. Similarly, the bottom effluent stream **208** may be fed into the reboiler **110**, which may receive energy **302** by being heated, and separates the bottom effluent stream **208** into a recycle stream **210** and a heavy hydrocarbon stream **212**. The heavy hydrocarbon stream **212** may then be fed into a separator **134** that separates an acid gas stream **250** from the heavy hydrocarbon stream **252**. The heavy hydrocarbon stream **252** may optionally be cooled by a heat exchanger **114**, for example an air cooler, to produce the heavy hydrocarbon stream **254**.

Returning to the light hydrocarbon stream **248**, the light hydrocarbon stream **248** may be fed into a compressor **112** that receives mechanical or electrical energy **304** and increases the pressure and/or temperature of the light hydrocarbon stream **248**, thereby creating a compressed light hydrocarbon stream **216**. The compressed light hydrocarbon stream **216** may then be fed into a heat exchanger **118** that uses a chilled carbon dioxide-lean stream **230** to reduce the temperature of the compressed light hydrocarbon stream **216**, thereby producing a chilled light hydrocarbon stream **224**. A second separation unit **103** that comprises one or more of a separator **120**, a reboiler **124**, and a condenser **122** may then remove at least some of the carbon dioxide from the chilled light hydrocarbon stream **224**. Specifically, the separator **120** separates the chilled light hydrocarbon stream **224** into a heavy effluent stream **236** and a light effluent stream **226**. The light effluent stream **226** may be fed into the condenser **122**, which may give off energy **306** by being cooled, and separates the light effluent stream **226** into a reflux stream **228** and the chilled carbon dioxide-lean stream **230**. The chilled carbon dioxide-lean stream **230** may then be passed through the heat exchangers **118**, **102** and into a hydrocarbon sweetening process **130**. The hydrocarbon sweetening process **130** may be any process that removes carbon dioxide from a hydrocarbon stream to make the hydrocarbon stream suitable for transportation and/or further processing. Persons of ordinary skill in the art are aware of numerous different hydrocarbon sweetening processes **130**, as illustrated by *Field Processing of Petroleum, Vol. 1: Natural Gas* by Manning et al., incorporated herein by reference as if reproduced in its entirety. Several examples of the hydrocarbon sweetening process **130** are discussed in detail below.

Returning to the separator **120**, the heavy effluent stream **236** may be fed into the reboiler **124**, which may receive energy **308** in the form of heat, and separates the heavy effluent stream **236** into a recycle stream **238** and a cooled carbon dioxide-rich stream **240**. The cooled carbon dioxide-rich stream **240** may optionally be combined with the acid gas stream **250**, if desired. The cooled carbon dioxide-rich stream **240** may then be fed through a heat exchanger **126** that further cools the cooled carbon dioxide-rich stream **240** by removing energy **310** from the cooled carbon dioxide-rich stream **240**, thereby producing the chilled carbon dioxide-rich stream **242**. The chilled carbon dioxide-rich stream **242** may also be fed to a pump **128** that uses energy **314** to pump the carbon dioxide-rich stream **244** to another location, perhaps for injection into a subterranean formation.

FIG. **2** illustrates another embodiment of the carbon dioxide fractionalization process **100**. Similar to the embodiment shown in FIG. **1**, the carbon dioxide fractionalization process **100** shown in FIG. **2** separates the hydrocarbon feed stream **200** into the heavy hydrocarbon stream **212**, the carbon dioxide-rich stream **244**, and the carbon dioxide-lean stream **234**, the compositions of which are discussed in detail below. The carbon dioxide fractionalization process **100** receives the hydrocarbon feed stream **200** and passes the hydrocarbon feed stream **200** through a heat exchanger **102** that uses the cooled carbon dioxide-lean stream **232** to reduce the temperature of the hydrocarbon feed stream **200**. After the cooled hydrocarbon feed stream **202** exits the heat exchanger **102**, the hydrocarbon feed stream **200** is fed into the optional heat exchanger **104**, which further cools the cooled hydrocarbon feed stream **202** by removing some of its energy **300**, thereby producing a cooled hydrocarbon feed stream **202**.

A first separation unit **101** that comprises one or more of separators **106**, **108** and the reboiler **110** may then remove the heavy hydrocarbons from the cooled hydrocarbon feed stream **202**. Specifically, the cooled hydrocarbon feed stream **202** may be fed into a separator **106** that separates the cooled hydrocarbon feed stream **202** into a light fraction **220** and a heavy fraction **206**. In an embodiment, the light fraction **220** may be a vapor phase and the heavy fraction **206** may be a liquid phase. The light fraction **220** may be combined with the compressed light hydrocarbon stream **216** in a mixer **116** and the heavy fraction **206** may be fed into the separator **108**. The separator **108** separates the heavy fraction **206** into a bottom effluent stream **208** and a top effluent stream **214**. The bottom effluent stream **208** may be fed into a reboiler **110**, which may receive energy **302** by being heated, and separates the bottom effluent stream **208** into a recycle stream **210** and the heavy hydrocarbon stream **212**. The top effluent **214** may be fed into the compressor **112** that receives mechanical or electrical energy **304** and increases the pressure and/or temperature of the top effluent **214**, thereby creating a compressed light hydrocarbon stream **216**. The compressed light hydrocarbon stream **216** may optionally be cooled, for example, by the heat exchanger **114**, which may be an air cooler, to produce a cooled light hydrocarbon stream **218**. The cooled light hydrocarbon stream **218** may then be mixed with the light fraction **220** in the mixer **116**. The resulting mixed light hydrocarbon stream **222** may then be processed as described above for the compressed light hydrocarbon stream **216** in FIG. **1** to produce the carbon dioxide-lean stream **234**.

The hydrocarbon feed stream **200** may contain a mixture of hydrocarbons and carbon dioxide. Numerous types of hydrocarbons may be present in the hydrocarbon feed stream **200**, including methane, ethane, propane, i-butane, n-butane, i-pentane, n-pentane, hexane, octane, and other hydrocarbon compounds. For example, the hydrocarbon feed stream **200** may contain from about 10 percent to about 60 percent methane, no more than about 10 percent ethane, and no more than about 5 percent propane and heavier hydrocarbons (C_{3+}). Although the hydrocarbon feed stream **200** may contain any carbon dioxide concentration, in various embodiments the hydrocarbon feed stream **200** contains from about 10 percent to about 90 percent, from about 30 percent to about 80 percent, or from about 50 percent to about 70 percent of the carbon dioxide. The hydrocarbon feed stream **200** may also include other compounds such as water, nitrogen, hydrogen sulfide (H_2S), and/or other acid gases. Finally, the hydrocarbon feed stream **200** may be in any state including a liquid state, a vapor state, or a combination of liquid and vapor states. Finally, unless otherwise stated, the percentages herein are provided on a mole basis.

Similar to the hydrocarbon feed stream **200**, the carbon dioxide-lean stream **234** may contain a mixture of hydrocarbons and carbon dioxide. Specifically, the composition of the carbon dioxide-lean stream **234** may contain an increased methane concentration and a decreased carbon dioxide concentration compared to the hydrocarbon feed stream **200**. In embodiments, the carbon dioxide-lean stream **234** contains less than about 60 percent, from about 20 percent to about 50 percent, or from about 30 percent to about 40 percent of the carbon dioxide. In yet other embodiments, the carbon dioxide concentration in the carbon dioxide-lean stream **234** is at least about 20 percent, at least about 40 percent, or at least about 60 percent less than the carbon dioxide concentration present in the hydrocarbon feed stream **200**. The carbon dioxide-lean stream **234** may also contain a reduced concentration of C_{3+} compared to the hydrocarbon feed stream **200**. In various embodiments, the carbon dioxide-lean stream **234** comprises less than about 5 percent, less than about 1 percent, or is substantially free of C_{3+}. In yet other embodiments, the C_{3+} concentration in the carbon dioxide-lean stream **234** is at least about 20 percent, at least about 40 percent, or at least about 60 percent less than the C_{3+} concentration present in the hydrocarbon feed stream **200**. Finally, in other embodiments, the carbon dioxide-lean stream **234** contains at least about 90 percent, at least about 98 percent, or at least about 99 percent of a combination of methane and carbon dioxide.

The heavy hydrocarbon streams **212**, **252**, **254** may contain a mixture of heavy hydrocarbons and some other compounds. Specifically, the composition of the heavy hydrocarbon streams **212**, **252**, **254** contains an increased C_{3+} concentration and a decreased methane concentration, ethane, and carbon dioxide compared to the hydrocarbon feed stream **200**. In embodiments, the heavy hydrocarbon streams **212**, **252**, **254** comprises at least about 90 percent, at least about 95 percent, or at least about 99 percent C_{3+}. In other embodiments, the heavy hydrocarbon streams **212**, **252**, **254** comprises less than about 5 percent, less than about 1 percent, or is substantially free of methane and/or ethane. In yet other embodiments, the heavy hydrocarbon streams **212**, **252**, **254** contains less than about 10 percent, less than about 5 percent, or less than about 1 percent of the carbon dioxide. Alternatively, the heavy hydrocarbon streams **212**, **252**, **254** comprises at least about 20 percent, at least about 40 percent, or at least about 60 percent less carbon dioxide than the hydrocarbon feed stream **200**. In an embodiment, the heavy hydrocarbon streams **212**, **252**, **254** described herein are suitable for use or sale as natural gas liquids (NGL).

The carbon dioxide-rich stream **244** described herein may comprise a mixture of hydrocarbons and carbon dioxide. Specifically, the carbon dioxide-rich stream **244** contains a decreased concentration of hydrocarbons and an increased carbon dioxide concentration compared to the hydrocarbon feed stream **200**. In various embodiments, the carbon dioxide-rich stream **244** comprises less than about 10 percent, less than about 5 percent, or is substantially free of hydrocarbons. In other embodiments, the carbon dioxide-rich stream **244** contains at least about 80 percent, at least about 90 percent, or at least about 95 percent of the carbon dioxide. The carbon dioxide-rich stream **244** described herein may be vented, transported, sold, or used for other purposes including reinjection into a subterranean formation.

The acid gas stream **250** described herein may comprise a mixture of hydrocarbons and at least one acid gas, such as H_2S or carbon dioxide. Specifically, the composition of the acid gas stream **250** may contain a decreased hydrocarbon concentration and an increased acid gas concentration compared to the hydrocarbon feed stream **200**. In various embodiments, the acid gas stream **250** comprises less than about 10 percent, less than about 5 percent, or is substantially free of hydrocarbons. In other embodiments, the acid gas stream **250** contains at least about 90 percent, at least about 95 percent, or at least about 99 percent of the acid gas. The acid gas stream **250** described herein may be vented, sold, reinjected, or otherwise disposed of as desired.

Although the hydrocarbon sweetening process **130** may be any sweetening process, in one embodiment the hydrocarbon sweetening process **130** is a physical solvent process. The physical solvent process sweetens the hydrocarbon stream by using an organic solvent to absorb the carbon dioxide from the hydrocarbon stream. Examples of these physical solvents include SELEXOL®, RECTISOL®, PURISOL®, and FLUOR® solvents such as propylene carbonate. The physical solvent process begins by contacting the carbon dioxide-lean stream **234** with the solvent at high pressure. The solvent absorbs the carbon dioxide such that subsequent separation of the solvent from the hydrocarbons produces a hydrocarbon stream with a relatively low carbon dioxide concentration. The carbon dioxide-loaded solvent is then regenerated by lowering the pressure of the solvent, typically through a series of flash drums, which causes the carbon dioxide to separate from the solvent. The solvent is then compressed and recycled into the hydrocarbon stream, while the carbon dioxide is vented or sold.

Alternatively, the hydrocarbon sweetening process **130** may be a membrane separation process. Membrane separation processes use membranes to separate carbon dioxide from the carbon dioxide-lean stream **234** at the molecular level. Specifically, the pores in the membranes are sized to allow carbon dioxide to pass through the membrane and form a permeate gas, while the larger hydrocarbon molecules bypass the membrane and form a residue gas. Depending on the composition of the hydrocarbons, this configuration may be reversed such that the carbon dioxide forms the residue gas and the hydrocarbons form the permeate gas. Because the membrane process is dependent on, among other factors, the composition of the hydrocarbons, the selection of the pore size is best determined by persons of ordinary skill in the art.

In yet another embodiment, the hydrocarbon sweetening process **130** may be a carbon dioxide recovery process. One example of a suitable carbon dioxide recovery process is the Ryan-Holmes process. The Ryan-Holmes process uses a solvent and a plurality of columns to separate the carbon dioxide-lean stream **234** into a carbon dioxide-rich stream, a methane-rich stream, an ethane-rich stream, and a heavy hydrocarbon stream. The columns may include a demethanizer, a carbon dioxide recovery unit, a propane recovery unit, and a solvent recovery unit. The columns are arranged in series with the solvent being recycled to the first column in the series. The specific arrangement of the various columns depends on the composition of the feed hydrocarbon stream and is best determined by persons of ordinary skill in the art. Finally, persons of ordinary skill in the art will appreciate that the hydrocarbon sweetening process **130** may be a process other than the exemplary processes described herein.

When the carbon dioxide fractionalization process **100** is implemented prior to a hydrocarbon sweetening process **130**, the processing capacity of the hydrocarbon sweetening process **130** is increased. Specifically, the processing capacity of the hydrocarbon sweetening process **130** may be directly proportional to the decrease in carbon dioxide concentration between the hydrocarbon feed stream **200** and the carbon dioxide-lean stream **234**. For example, if the carbon dioxide concentration of the carbon dioxide-lean stream **234** is half of the carbon dioxide concentration of the hydrocarbon feed stream **200**, then the processing capacity of the hydrocarbon sweetening process **130** is doubled. In addition, the processing capacity of the hydrocarbon sweetening process **130** may be directly proportional to the decrease in flow rate between the hydrocarbon feed stream **200** and the carbon dioxide-lean stream **234**. For example, if the flow rate of the carbon dioxide-lean stream **234** is half of the flow rate of the hydrocarbon feed stream **200**, then the processing capacity of the hydrocarbon sweetening process

130 is also doubled. The two affects may also be cumulative such that if the carbon dioxide concentration of the carbon dioxide-lean stream 234 is half of the carbon dioxide concentration of the hydrocarbon feed stream 200 and the flow rate of the carbon dioxide-lean stream 234 is half of the flow rate of the hydrocarbon feed stream 200, then the processing capacity of the hydrocarbon sweetening process 130 is increased by a factor of four.

The separators 106, 108, 120, 134 may be any of a variety of process equipment suitable for separating a stream into two separate streams having different compositions, states, temperatures, and/or pressures. For example, one or more of the separators 106, 108, 120, 134 may be a column having trays, packing, or some other type of complex internal structure. Examples of such columns include scrubbers, strippers, absorbers, adsorbers, packed columns, and distillation columns having valve, sieve, or other types of trays. Such columns may employ weirs, downspouts, internal baffles, temperature, and/or pressure control elements. Such columns may also employ some combination of reflux condensers and/or reboilers, including intermediate stage condensers and reboilers. Alternatively, one or more of the separators 106, 108, 120, 134 may be a phase separator. A phase separator is a vessel that separates an inlet stream into a substantially vapor stream and a substantially liquid stream, such as a knock-out drum or a flash drum. Such vessels may have some internal baffles, temperature, and/or pressure control elements, but generally lack any trays or other type of complex internal structure commonly found in columns. Finally, one or more of the separators 106, 108, 120, 134 may be any other type of separator, such as a membrane separator.

The reboilers 110, 124 and condensers 122, 132 described herein may be any of a variety of process equipment suitable for changing the temperature and/or separating any of the streams described herein. In embodiments, the reboilers 110, 124 and the condensers 122, 132 may be any vessel that separates an inlet stream into a substantially vapor stream and a substantially liquid stream. These vessels typically have some internal baffles, temperature, and/or pressure control elements, but generally lack any trays or other type of complex internal structure found in other vessels. In specific embodiments, heat exchangers and kettle-type reboilers may be used as the reboilers 110, 124 and condensers 122, 132 described herein.

The heat exchangers 102, 104, 114, 118, 126 described herein may be any of a variety of process equipment suitable for heating or cooling any of the streams described herein. Generally, heat exchangers 102, 104, 114, 118, 126 are relatively simple devices that allow heat to be exchanged between two fluids without the fluids directly contacting each other. In the case of an air cooler, one of the fluids is atmospheric air, which may be forced over tubes or coils using one or more fans. The types of heat exchangers 102, 104, 114, 118, 126 suitable for use with the carbon dioxide fractionalization process 100 include shell and tube, kettle-type, air cooled, hairpin, bayonet, and plate-fin heat exchangers.

The compressor 112 and pump 128 described herein may be any of a variety of process equipment suitable for increasing the pressure, temperature, and/or density of any of the streams described herein. Generally, compressors are associated with vapor streams and pumps are associated with liquid streams; however such a limitation should not be read into the present processes as the compressors and pumps described herein may be interchangeable based upon the specific conditions and compositions of the streams. The types of compressors and pumps suitable for the uses described herein include centrifugal, axial, positive displacement, rotary, and reciprocating compressors and pumps. Finally, the carbon dioxide fractionalization process 100 may contain additional compressors and/or pumps other than those described herein.

The mixer 116 described herein may either be a dynamic mixer or a static mixer. Dynamic mixers are mixers that employ motion or mechanical agitation to mix two or more streams. For example, a dynamic mixer may be a tank with a paddle operating either in a continuous or batch mode. In contrast, static mixers are mixers that do not employ any motion or mechanical agitation to mix two or more streams. For example, a static mixer may be a convergence of piping designed to combine two streams, such as a pipe tee. Either type of mixer may be configured with internal baffles to promote the mixing of the feed streams.

The energy streams 300, 302, 304, 306, 308, 310, 312, 314 described herein may be derived from any number of suitable sources. For example, heat may be added to a process stream using steam, turbine exhaust, or some other hot fluid and a heat exchanger. Similarly, heat may be removed from a process stream by using a refrigerant, air, or some other cold fluid and a heat exchanger. Further, electrical energy can be supplied to compressors, pumps, and other mechanical equipment to increase the pressure or other physical properties of a fluid. Similarly, turbines, generators, or other mechanical equipment can be used to extract physical energy from a stream and optionally convert the physical energy into electrical energy. Persons of ordinary skill in the art are aware of how to configure the processes described herein with the required energy streams 300, 302, 304, 306, 308, 310, 312, 314. In addition, persons of ordinary skill in the art will appreciate that the carbon dioxide fractionalization process 100 may contain additional equipment, process steams, and/or energy streams other than those described herein.

The carbon dioxide fractionalization process 100 described herein has many advantages. One advantage is that it purifies a hydrocarbon stream used by one of the hydrocarbon sweetening processes 130 described above. Specifically, the carbon dioxide fractionalization process 100 purifies the hydrocarbon stream by removing some of the carbon dioxide and C_{3+} from the hydrocarbon stream. The purification of the hydrocarbon stream improves the performance of the hydrocarbon sweetening process 130 by reducing the carbon dioxide and C_{3+} loading on the hydrocarbon sweetening process 130. The reduction in loading increases the processing capacity for the hydrocarbon sweetening process 130, which is particularly advantageous for existing processing facilities. Moreover, the addition of the carbon dioxide fractionalization process 100 to existing hydrocarbon sweetening processes 130 may reduce the energy requirements of the combined processes. Specifically, the carbon dioxide fractionalization process 100 liquefies some of the carbon dioxide and C_{3+} in the hydrocarbon feed and feeds the carbon dioxide-lean stream 234 to the sweetening process 130, thereby reducing the compression requirements within the hydrocarbon sweetening process 130. The reduction in compression requirements may decrease the total energy requirements of the two processes per unit amount of hydrocarbons, e.g. Btu/SCF (British thermal units per standard cubic foot of gas). Other advantages will be apparent to persons of ordinary skill in the art.

EXAMPLES

In one example, a process simulation was performed using the carbon dioxide fractionalization process 100 shown in FIG. **1**. The simulation was performed using the Hyprotech Ltd. HYSYS Process v2.1.1 (Build 3198) software package. The carbon dioxide fractionalization process **100** separated a West Texas hydrocarbon feed containing about 63 percent carbon dioxide into a carbon dioxide-lean stream **234** containing about 43 percent carbon dioxide, a carbon dioxide-rich stream **244** containing about 95 percent carbon dioxide, an acid gas stream **250** containing about 100 percent carbon dioxide and trace amounts of other acid gases, and a heavy hydrocarbon stream containing about 99 percent C_{3+}. It is notable that the process produces 454 gallons per minute of pipeline-grade liquefied carbon dioxide. The carbon dioxide produced by a SELEXOL® plant without this process produces a similar amount of gaseous carbon dioxide, but at atmospheric pressure or at a vacuum. The compression requirements for such a gaseous carbon dioxide stream are large, e.g. 25,000 BTU per thousand standard cubic feet (MSCF), and are generally cost prohibitive. Thus, the present process allows carbon dioxide to be economically recovered and reused, unlike the prior processes. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 1, 2, and 3 below. The specified values are indicated by an asterisk (*). The physical properties are provided in degrees Fahrenheit (F), pounds per square inch gauge (psig), million standard cubic feet per day (MMSCFD), pounds per hour (lb/hr), U.S. gallons per minute (USGPM), and British thermal units per hour (Btu/hr).

TABLE 1A

Material Streams				
Name	200	248	202	224
Vapor Fraction	1.0000	1.0000	1.0000	1.0000
Temperature (F.)	100.0*	−15.92	99.00*	60.00*
Pressure (psig)	485.3*	385.3	480.3	980.3
Molar Flow (MMSCFD)	100.0*	99.82	100.0	99.82
Mass Flow (lb/hr)	3.731e+05	3.713e+05	3.731e+05	3.713e+05
Liquid Volume Flow (USGPM)	1176	1171	1176	1171
Heat Flow (Btu/hr)	−1.305e+09	−1.316e+09	−1.305e+09	−1.315e+09

TABLE 1B

Material Streams				
Name	230	240	232	234
Vapor Fraction	1.0000	0.0000	1.0000	1.0000
Temperature (F.)	−5.769	65.16	92.33	92.78
Pressure (psig)	925.3	935.3	920.3	915.3
Molar Flow (MMSCFD)	61.13	38.68	61.13	61.13
Mass Flow (lb/hr)	1.896e+05	1.817e+05	1.896e+05	1.896e+05
Liquid Volume Flow (USGPM)	716.7	454.5	716.7	716.7
Heat Flow (Btu/hr)	−6.242e+08	−7.078e+08	−6.145e+08	−6.145e+08

TABLE 1C

Material Streams				
Name	244	242	218	212
Vapor Fraction	0.0000	0.0000	1.0000	0.0000
Temperature (F.)	72.39	55.00	123.3	264.0
Pressure (psig)	1785*	930.3	985.3*	395.3
Molar Flow (MMSCFD)	38.68	38.68	99.82	0.1832
Mass Flow (lb/hr)	1.817e+05	1.817e+05	3.713e+05	1801
Liquid Volume Flow (USGPM)	454.5	454.5	1171	5.233
Heat Flow (Btu/hr)	−7.092e+08	−7.100e+08	−1.306e+09	−1.905e+06

TABLE 1D

Material Streams				
		Name		
		250	252	254
Vapor Fraction		1.0000	0.0000	0.0000
Temperature	(F.)	100.0*	265.2*	120.0*
Pressure	(psig)	485.3*	485.3*	465.3*
Molar Flow	(MMSCFD)	0.02473	0.1585	0.1585
Mass Flow	(lb/hr)	119.5	1682	1682
Liquid Volume Flow	(USGPM)	0.2892	4.944	4.944
Heat Flow	(Btu/hr)	−4.610e+05	−1.444e+06	−1.593e+06

TABLE 2A

Stream Compositions				
	Name			
	200	248	202	224
Comp Mole Frac (H2S)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0051*	0.0051	0.0051	0.0051
Comp Mole Frac (CO2)	0.6308*	0.6317	0.6308	0.6317
Comp Mole Frac (Methane)	0.3570*	0.3577	0.3570	0.3577
Comp Mole Frac (Ethane)	0.0037*	0.0037	0.0037	0.0037
Comp Mole Frac (Propane)	0.0013*	0.0013	0.0013	0.0013
Comp Mole Frac (i-Butane)	0.0002*	0.0002	0.0002	0.0002
Comp Mole Frac (n-Butane)	0.0005*	0.0004	0.0005	0.0004
Comp Mole Frac (i-Pentane)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0007*	0.0000	0.0007	0.0000
Comp Mole Frac (n-Octane)	0.0008*	0.0000	0.0008	0.0000
Comp Mole Frac (H2O)	0.0000*	0.0000	0.0000	0.0000

TABLE 2B

Stream Compositions				
	Name			
	230	240	232	234
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0083	0.0001	0.0083	0.0083
Comp Mole Frac (CO2)	0.4303	0.9500	0.4303	0.4303

TABLE 2B-continued

Stream Compositions				
	Name			
	230	240	232	234
Comp Mole Frac (Methane)	0.5568	0.0430	0.5568	0.5568
Comp Mole Frac (Ethane)	0.0041	0.0031	0.0041	0.0041
Comp Mole Frac (Propane)	0.0005	0.0025	0.0005	0.0005
Comp Mole Frac (i-Butane)	0.0000	0.0004	0.0000	0.0000
Comp Mole Frac (n-Butane)	0.0000	0.0010	0.0000	0.0000
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Octane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000

TABLE 2C

Stream Compositions				
	Name			
	244	242	218	212
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0001	0.0001	0.0051	0.0000
Comp Mole Frac (CO2)	0.9500	0.9500	0.6317	0.1350
Comp Mole Frac (Methane)	0.0430	0.0430	0.3577	0.0001
Comp Mole Frac (Ethane)	0.0031	0.0031	0.0037	0.0050
Comp Mole Frac (Propane)	0.0025	0.0025	0.0013	0.0142
Comp Mole Frac (i-Butane)	0.0004	0.0004	0.0002	0.0078
Comp Mole Frac (n-Butane)	0.0010	0.0010	0.0004	0.0472
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0000	0.0000	0.0000	0.3813
Comp Mole Frac (n-Octane)	0.0000	0.0000	0.0000	0.4094
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000

TABLE 2D

Stream Compositions			
	Name		
	250	252	254
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0000
Comp Mole Frac (CO2)	1.0000	0.0000	0.0000

TABLE 2D-continued

Stream Compositions			
	Name		
	250	252	254
Comp Mole Frac (Methane)	0.0000	0.0001	0.0001
Comp Mole Frac (Ethane)	0.0000	0.0058	0.0058
Comp Mole Frac (Propane)	0.0000	0.0164	0.0164
Comp Mole Frac (i-Butane)	0.0000	0.0090	0.0090
Comp Mole Frac (n-Butane)	0.0000	0.0545	0.0545
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0000	0.4408	0.4408
Comp Mole Frac (n-Octane)	0.0000	0.4733	0.4733
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000

TABLE 3

Energy Streams	
Name	HeatFlow (Btu/hr)
308	8.518e+06
302	3.623e+05
304	1.027e+07
306	2.505e+07
314	7.719e+05
310	2.184e+06
312	1.293e+07

In another example, a process simulation was performed using the carbon dioxide fractionalization process **100** shown in FIG. **2**. The simulation was performed using the Hyprotech Ltd. HYSYS Process v2.1.1 (Build 3198) software package. The carbon dioxide fractionalization process **100** separated a West Texas hydrocarbon feed containing about 63 percent carbon dioxide into a carbon dioxide-lean stream **234** containing about 36 percent carbon dioxide, a carbon dioxide-rich stream **244** containing about 95 percent carbon dioxide, and a heavy hydrocarbon stream containing about 93 percent C_{3+}. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 4, 5, and 6 below.

TABLE 4A

Material Streams					
		Name			
		200	204	206	222
Vapor Fraction		1.0000	0.8205	0.0000	1.0000
Temperature	(F.)	100.0*	22.00*	22.00	34.23
Pressure	(psig)	945.3*	935.3	935.3	935.3
Molar Flow	(MMSCFD)	300.0*	300.0	53.85	299.6
Mass Flow	(lb/hr)	1.119e+06	1.119e+06	2.343e+05	1.115e+06
Liquid Volume Flow	(USGPM)	3529	3529	640.1	3516
Heat Flow	(Btu/hr)	−3.932e+09	−3.988e+09	−8.836e+08	−3.961e+09

TABLE 4B

Material Streams					
		Name			
		214	212	202	218
Vapor Fraction		1.0000	0.0000	1.0000	1.0000
Temperature	(F.)	−5.027	335.1	47.95	100.0*
Pressure	(psig)	335.3	340.3	940.3	960.3*
Molar Flow	(MMSCFD)	53.41	0.4397	300.0	53.41
Mass Flow	(lb/hr)	2.299e+05	4409	1.119e+06	2.299e+05
Liquid Volume Flow	(USGPM)	627.1	12.95	3529	627.1
Heat Flow	(Btu/hr)	−8.582e+08	−4.030e+06	−3.957e+09	−8.564e+08

TABLE 4C

Material Streams					
		Name			
		224	230	240	232
Vapor Fraction		1.0000	1.0000	0.00000	1.0000
Temperature	(F.)	32.00*	−20.00	61.65	−17.19
Pressure	(psig)	930.3	895.3	900.3	890.3
Molar Flow	(MMSCFD)	299.6	161.3	138.3	161.3
Mass Flow	(lb/hr)	1.115e+06	4.649e+05	6.501e+05	4.649e+05
Liquid Volume Flow	(USGPM)	3516	1890	1626	1890
Heat Flow	(Btu/hr)	−3.962e+09	−1.473e+09	−2.533e+09	−1.472e+09

TABLE 4D

Material Streams						
		Name				
		234	244	242	220	216
Vapor Fraction		1.0000	0.0000	0.0000	1.0000	1.0000
Temperature	(F.)	85.00*	73.48	55.00*	22.00	155.2
Pressure	(psig)	885.3	1785*	895.3	935.3	965.3
Molar Flow	(MMSCFD)	161.3	138.3	138.3	246.2	53.41
Mass Flow	(lb/hr)	4.649e+05	6.501e+05	6.501e+05	8.851e+05	2.299e+05
Liquid Volume Flow	(USGPM)	1890	1626	1626	2889	627.1
Heat Flow	(Btu/hr)	−1.446e+09	−2.535e+09	−2.538e+09	−3.105e+09	−8.518e+08

TABLE 5A

Stream Compositions				
	Name			
	200	204	206	220
Comp Mole Frac (H2S)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0051*	0.0051	0.0016	0.0051
Comp Mole Frac (CO2)	0.6308*	0.6308	0.8168	0.6316
Comp Mole Frac (Methane)	0.3570*	0.3570	0.1680	0.3576
Comp Mole Frac (Ethane)	0.0037*	0.0037	0.0037	0.0037
Comp Mole Frac (Propane)	0.0013*	0.0013	0.0020	0.0013
Comp Mole Frac (i-Butane)	0.0002*	0.0002	0.0004	0.0001
Comp Mole Frac (n-Butane)	0.0005*	0.0005	0.0011	0.0003
Comp Mole Frac (i-Pentane)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000*	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0007*	0.0007	0.0028	0.0002
Comp Mole Frac (n-Octane)	0.0008*	0.0008	0.0037	0.0001
Comp Mole Frac (H2O)	0.0000*	0.0000	0.0000	0.0000

TABLE 5B

Stream Compositions				
	Name			
	214	212	202	218
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0016	0.0000	0.0051	0.0016
Comp Mole Frac (CO2)	0.8229	0.0700	0.6308	0.8229
Comp Mole Frac (Methane)	0.1693	0.0000	0.3570	0.1693
Comp Mole Frac (Ethane)	0.0037	0.0000	0.0037	0.0037
Comp Mole Frac (Propane)	0.0018	0.0302	0.0013	0.0018
Comp Mole Frac (i-Butane)	0.0001	0.0252	0.0002	0.0001
Comp Mole Frac (n-Butane)	0.0003	0.0949	0.0005	0.0003
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0001	0.3260	0.0007	0.0001
Comp Mole Frac (n-Octane)	0.0000	0.4537	0.0008	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000

TABLE 5C

Stream Compositions				
	Name			
	224	230	240	232
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0051	0.0094	0.0000	0.0094
Comp Mole Frac (CO2)	0.6316	0.3586	0.9500	0.3586
Comp Mole Frac (Methane)	0.3576	0.6275	0.0428	0.6275
Comp Mole Frac (Ethane)	0.0037	0.0041	0.0032	0.0041
Comp Mole Frac (Propane)	0.0013	0.0004	0.0023	0.0004
Comp Mole Frac (i-Butane)	0.0001	0.0000	0.0003	0.0000
Comp Mole Frac (n-Butane)	0.0003	0.0000	0.0007	0.0000
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0002	0.0000	0.0005	0.0000
Comp Mole Frac (n-Octane)	0.0001	0.0000	0.0002	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000

TABLE 5D

Stream Compositions					
	Name				
	234	244	242	220	216
Comp Mole Frac (H2S)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Nitrogen)	0.0094	0.0000	0.0000	0.0059	0.0016
Comp Mole Frac (CO2)	0.3586	0.9500	0.9500	0.5901	0.8229
Comp Mole Frac (Methane)	0.6275	0.0428	0.0428	0.3984	0.1693
Comp Mole Frac (Ethane)	0.0041	0.0032	0.0032	0.0037	0.0037
Comp Mole Frac (Propane)	0.0004	0.0023	0.0023	0.0011	0.0018
Comp Mole Frac (i-Butane)	0.0000	0.0003	0.0003	0.0001	0.0001
Comp Mole Frac (n-Butane)	0.0000	0.0007	0.0007	0.0003	0.0003
Comp Mole Frac (i-Pentane)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Pentane)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (n-Hexane)	0.0000	0.0005	0.0005	0.0002	0.0001
Comp Mole Frac (n-Octane)	0.0000	0.0002	0.0002	0.0001	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE 6

Energy Streams	
Name	Heat Flow (Btu/hr)
300	3.107e+07
302	2.138e+07
304	6.401e+06
306	7.371e+07
308	3.014e+07
314	2.890e+06
310	4.946e+06

While preferred embodiments of the invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit and teachings of the invention. The embodiments described herein are exemplary only, and are not intended to be limiting. Many variations and modifications of the invention disclosed herein are possible and are within the scope of the invention. Specifically, while the process is described in terms of a continuous process, it is contemplated that the process can be implemented as a batch process. In addition, where numerical ranges or limitations are expressly stated, such express ranges or limitations should be understood to include iterative ranges or limitations of like magnitude falling within the expressly stated ranges or limitations (e.g., from about 1 to about 10 includes, 2, 3, 4, etc.; greater than 0.10 includes 0.11, 0.12, 0.13, etc.). Use of the term "optionally" with respect to any element of a claim is intended to mean that the subject element is required, or alternatively, is not required. Both alternatives are intended to be within the scope of the claim. Use of broader terms such as comprises, includes, having, etc. should be understood to provide support for narrower terms such as consisting of, consisting essentially of, comprised substantially of, etc. Moreover, the percentages described herein may be mole fraction, weight fraction, or volumetric fraction.

Accordingly, the scope of protection is not limited by the description set out above but is only limited by the claims which follow, that scope including all equivalents of the subject matter of the claims. Each and every claim is incorporated into the specification as an embodiment of the present invention. Thus, the claims are a further description and are an addition to the preferred embodiments of the present invention. The discussion of a reference in the herein is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. The disclosures of all patents, patent applications, and publications cited herein are hereby incorporated by reference, to the extent that they provide exemplary, procedural or other details supplementary to those set forth herein.

What is claimed is:

1. A process comprising:
- receiving a hydrocarbon feed stream comprising carbon dioxide;
- separating the hydrocarbon feed stream into a light hydrocarbon stream and a heavy hydrocarbon stream;
- separating the light hydrocarbon stream into a carbon dioxide-rich stream and a carbon dioxide-lean stream;
- heating the carbon dioxide-lean stream to produce a heated carbon dioxide-lean stream; and
- feeding the heated carbon dioxide-lean stream into a hydrocarbon sweetening process, thereby increasing the processing capacity of the hydrocarbon sweetening process compared to the processing capacity of the hydrocarbon sweetening process when fed the hydrocarbon feed stream.

2. The process of claim **1**, wherein the hydrocarbon sweetening process comprises:
- absorbing at least some of the carbon dioxide from the heated carbon dioxide-lean stream with a solvent;
- separating the solvent from the heated carbon dioxide-lean stream; and
- releasing at least some of the carbon dioxide from the solvent by lowering the pressure of the solvent.

3. The process of claim **1**, wherein the hydrocarbon sweetening process comprises separating at least some of the carbon dioxide from the heated carbon dioxide-lean stream using a membrane.

4. The process of claim **1**, wherein the hydrocarbon sweetening process comprises:
- absorbing at least some of the carbon dioxide from the heated carbon dioxide-lean stream with a solvent;
- separating a methane-rich stream from the solvent;
- separating an ethane-rich stream from the solvent; and
- separating a heavy hydrocarbon stream from the solvent.

5. The process of claim 1, wherein the hydrocarbon feed stream contains from about 30 molar percent to about 80 molar percent carbon dioxide.

6. The process of claim 1, wherein the carbon dioxide-lean stream contains less than about 60 molar percent carbon dioxide and less than about 5 molar percent C_{3+}.

7. The process of claim 1, wherein the carbon dioxide-lean stream contains at least about 95 molar percent of a combination of methane and carbon dioxide.

8. The process of claim 1, wherein the heavy hydrocarbon stream contains at least about 90 molar percent C_{3+}.

9. The process of claim 1, wherein the carbon dioxide-rich stream contains at least about 95 molar percent carbon dioxide.

10. The process of claim 1, further comprising

transferring the carbon dioxide-rich stream to a pipeline for injection into a subterranean formation.

11. The process of claim 1, wherein the increase in processing capacity of the hydrocarbon sweetening process is directly proportional to the decrease in carbon dioxide concentration between the hydrocarbon feed stream and the heated carbon dioxide-lean stream, and the decrease in flow rate between the hydrocarbon feed stream and the heated carbon dioxide-lean stream.

12. An apparatus comprising:

a first separator that receives a hydrocarbon feed stream containing carbon dioxide and produces a heavy hydrocarbon stream and a light hydrocarbon stream;

a second separator that receives the light hydrocarbon stream and produces a carbon dioxide-rich stream and a carbon dioxide-lean stream;

a heat exchanger that heats the carbon dioxide-lean stream to produce a heated carbon dioxide-lean stream; and

a physical solvent process, a membrane process, or a carbon dioxide recovery process that receives the heated carbon dioxide-lean stream.

13. The apparatus of claim 12, wherein the first separator comprises:

a column that receives the hydrocarbon feed stream and produces the light hydrocarbon stream and the heavy hydrocarbon stream; and

a drum that receives the heavy hydrocarbon stream and produces an acid gas stream and a heavy hydrocarbon stream.

14. The apparatus of claim 12, wherein the first separator comprises:

a drum that receives the hydrocarbon feed stream and produces a light fraction and a heavy fraction;

a column that receives the heavy fraction and produces the light hydrocarbon stream and the heavy hydrocarbon stream, the light fraction being combined with the light hydrocarbon stream prior to the second separator.

15. The apparatus of claim 12, further comprising a second heat exchanger configured to use the carbon dioxide-lean stream to cool the light hydrocarbon stream.

16. The apparatus of claim 12, wherein the heat exchanger is configured to use the carbon dioxide-lean stream to cool the hydrocarbon feed stream.

17. A process comprising:

receiving a hydrocarbon feed stream comprising carbon dioxide;

cooling the hydrocarbon feed stream using a carbon dioxide-lean stream;

separating the cooled hydrocarbon feed stream into a light hydrocarbon stream and a heavy hydrocarbon stream;

compressing the light hydrocarbon stream;

cooling the compressed light hydrocarbon stream using the carbon dioxide-lean stream;

separating the compressed light hydrocarbon stream into a carbon dioxide-rich stream and the carbon dioxide-lean stream;

heating the carbon dioxide-lean stream to produce a heated carbon dioxide-lean stream; and

removing at least some of the carbon dioxide in the heated carbon dioxide-lean stream using a hydrocarbon sweetening process.

18. The process of claim 17, further comprising separating the heavy hydrocarbon stream into an acid gas stream and a heavy hydrocarbon stream.

19. The process of claim 17, wherein separating the cooled hydrocarbon feed stream into the light hydrocarbon stream and the heavy hydrocarbon stream comprises:

separating the cooled hydrocarbon feed stream into a light fraction and a heavy fraction;

separating the heavy fraction into the light hydrocarbon stream and the heavy hydrocarbon stream; and

combining the light fraction with the light hydrocarbon stream.

20. The process of claim 17, wherein the hydrocarbon sweetening process is a physical solvent process, a membrane process, or a carbon dioxide recovery process.

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